State of California

Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2006, Through December 31, 2006

To Be Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

June 8, 2005

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A. THE PROPOSED DETERMINATION

GENERAL

Pursuant to Section 80110 of the California Water Code, the Rate Agreement between the State of California Department of Water Resources (the "Department" or "DWR") and the California Public Utilities Commission (the "Commission" or "CPUC"), dated March 8, 2002 (the "Rate Agreement"), and Division 23, Chapter 4, Sections 510–517 of the California Code of Regulations ("the Regulations"), the Department hereby issues its Proposed Determination of Revenue Requirements for the period January 1, 2006, through December 31, 2006 (the "2006 Proposed Determination)". Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Indenture under which the Department's Power Supply Revenue Bonds were issued (the "Bond Indenture").

In January and February of 2001, the Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the three California investor-owned utilities (the "Utilities" or "IOUs") namely, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E"). On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was signed into law, enacting California Water Code Division 27 (as subsequently amended, "the Act"). The Act authorized the Department to purchase the net short energy requirements of the IOUs. The term "net short" is used herein to mean total IOU customer energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department, in accordance with the Act, procured all of the net short requirements of the IOUs through the end of 2002 using a combination of long-term power contracts, short-term power contracts and wholesale energy purchases. After allowing for the energy provided under the Department's long-term power contracts, the amount of energy required to be purchased (initially on a short-term basis) to meet IOU customer needs is herein called the "residual net short." For purposes of the 2006 Proposed Determination, the residual net short for each IOU equals the projected amount of wholesale energy to be procured by such IOU on behalf of ratepayers in its service area.

If the Department had not entered into long-term contracts, a greater volume of net short energy would have been purchased in the spot market between January 2001 and December 2002, the period during which the Department had the responsibility for procuring the entire net short energy requirement. Similarly, after 2002, any net short energy requirements not provided under the Department's long-term contracts are to be purchased by the three IOUs, either as spot market purchases or under new contracts authorized by the Commission in accordance with Assembly Bill 57 ("AB 57"), which was enacted on September 24, 2002.

AB 57 provided for each of the IOUs to resume procurement of their customers' energy requirements, which are not served by the Department, beginning January 1, 2003. The legislation further required each utility to provide to the Commission an energy procurement plan, including a description of the required energy products for the utilities to meet their residual net short energy needs.

At the time the Department entered into long-term contracts, Assembly Bill 57 had not been enacted and it was uncertain when all three of the utilities would be sufficiently creditworthy to purchase their own residual net short energy requirements. The Commission commenced implementation of the energy procurement process contemplated by AB 57 for the first time in the fourth quarter of 2002.

On January 1, 2003, the IOUs resumed the responsibility of procuring the residual net short. Since that time, the Department's role in procuring power to meet the net short has been limited to the provision of power from contracts entered into by the Department prior to January 1, 2003.

The costs of the Department's purchases to meet the net short requirements of retail end use customers in the IOUs' service territories, including the costs of administering the long-term contracts, are to be recovered from payments made by customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations, the Rate Agreement and orders of the Commission. Among other things, the Rate Agreement contemplates a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).[1]

The Department funded its purchases of energy from January 17, 2001, through December 31, 2002, from three sources: payments collected from retail customers by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of $4.3 billion issued in June 2001 (the "Interim Loan"). In October and November of 2002, the State issued $11.263 billion of revenue bonds. The proceeds were applied to reimburse the General Fund, pay off of the Interim Loan, and create certain debt service reserves and operating reserves. Repayment of the bonds will be made from Bond Charges established under the Rate Agreement and applicable Decisions of the Commission and from amounts in the related accounts, as described in more detail herein.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Proposed Determination contains information on the amounts required to be recovered, on a cash basis, in the 2006 Revenue Requirement Period (calendar year 2006).

This 2006 Proposed Determination takes into account preliminary actual operating results of the Department through April 30, 2005 and projected operating results through the end of 2005.

[1] Under the Rate Agreement, the "Retail Revenue Requirement" is the amount to be recovered from "Power Charges" on IOU customers. The assessment on customers of Electric Service Providers of charges to recover Department Costs (e.g. "Direct Access Power Charge Revenues") reduces the amount of the "Retail Revenue Requirement," but has no material impact on the Department's costs.

For the 2006 Revenue Requirement Period, this Proposed Determination contains information regarding the following[2]: (a) the projected beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts projected to be on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal, premium, if any, and interest on all bonds as well as all other Bond Related Costs as and when the same are projected to become due, and the projected amount of Bond Charges required to be collected for such purpose; and (c) the amount needed to meet the Department's Costs, including all Retail Revenue Requirements.

PROPOSED DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department proposes to determine, on the basis of the materials presented and referred to by this 2006 Proposed Determination (including the materials referred to in Section H), that its cash basis revenue requirement for 2006 is $5.282 billion, consisting of $4.408 billion in Department Costs and $0.874 billion in Bond Related Costs.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with projected Department Costs ("Power Charge Accounts") for 2006. These figures are compared to those reflected in the Department's Revised 2005 Determination of Revenue Requirements for the period January 1, 2005 through December 31, 2005, published March 16, 2005 (the "Revised 2005 Determination").

A summary and comparison of the Department's revenue requirements and accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

[2] Where appropriate, the Department has provided information in this Proposed Determination on a quarterly basis. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis. Within this 2006 Proposed Determination, quantitative statistics presented in tabular form may not add due to rounding.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2006 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2005[1]
($ Millions)

Line	Description	2006[2]	2005[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	987	1,128	(141)
3	Priority Contract Account	-	63	(63)
4	Operating Reserve Account	555	595	(40)
5	**Total Beginning Balance in Power Charge Accounts**	**1,542**	**1,786**	**(244)**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	4,408	3,808	600
8	Extraordinary Receipts[5]	-	11	(11)
9	Other Revenue[6]	193	236	(43)
10	Interest Earnings on Fund Balances	24	26	(2)
11	**Total Power Charge Accounts Operating Revenues**	**4,625**	**4,081**	**544**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	36	45	(9)
14	Total Power Costs	4,602	4,458	144
15	Gas Collateral Costs	-	52	(52)
16	Extraordinary Contract Expenses	(59)	(33)	(27)
17	**Total Power Charge Accounts Operating Expenses**	**4,579**	**4,522**	**57**
18	Net Operating Revenues	46	(441)	487
19	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	-	-
20	Total Net Revenues	46	(441)	487
21	**Ending Aggregate Balance in Power Charge Accounts**	**1,588**	**1,345**	**243**

Target Minimum Power Charge Account Balances	**Target (Millions of Dollars)**		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	354	275	79
Operating Reserve Account: covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	823	555	268
Total Operating Reserves:	1,177	829	348

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the Revised 2005 Determination.
[4]CRS Power Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Includes funds distributed to the Department as specified in settlement agreements with various energy suppliers; details related to individual settlement receipts are further discussed in Section D.
[6]Includes revenues received by the Department from surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S 2006 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2005[1]
($ Millions)

Line	Description	2006[2]	2005[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	168	199	(31)
3	Bond Charge Payment Account	582	572	10
4	Debt Service Reserve Account	927	927	(0)
5	**Total Beginning Balance in Bond Charge Accounts**	**1,677**	**1,698**	**(20)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	874	850	24
8	Interest Earnings on Fund Balances	46	47	(0)
9	**Total Bond Charge Accounts Revenues**	**921**	**897**	**24**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds[5]	926	922	5
12	**Total Bond Charge Accounts Expenses**	**926**	**922**	**5**
13	Net Bond Charge Revenues	(6)	(25)	19
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(6)	(25)	19
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,671**	**1,673**	**(1)**

Target Minimum Bond Charge Account Balances	Target (Millions of Dollars)		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	77 - 79	76 - 78	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	238 - 849	237 - 834	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the Revised 2005 Determination.
[4]CRS Power Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Debt service on bonds includes net qualified swap payments.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS

The Department may revise its revenue requirements for the 2006 Revenue Requirement Period given the potential for significant or material changes in the California energy market, the status of market participants and the Department's associated obligations and operations, and many other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirements accordingly.

Several relevant factors are discussed in more detail within Section D.

B. BACKGROUND

THE ACT

Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that "any just and reasonable" review shall be conducted and determined by the Department. In addition, Section 80134 of the Water Code provides that:

> "(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:
>
> > "(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.
> >
> > "(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.
> >
> > "(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.
> >
> > "(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.
> >
> > "(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.
> >
> > "(6) The administrative costs of the Department incurred in administering this division.
>
> "(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110."

THE RATE AGREEMENT

In February 2002, the Commission issued a decision adopting the Rate Agreement between the Commission and the Department establishing the procedures to be followed to calculate and adjust the charges to customers for Department power, such that the Department is assured of recovering its Retail Revenue Requirements.[3] Among other purposes, the adoption of the Rate Agreement served to facilitate the issuance of bonds that enabled the repayment of the General Fund and Interim Loan and the funding of appropriate reserves for the bonds. On November 14, 2002, the final bond issue was completed. The General Fund and Interim Loan were repaid.

The Rate Agreement provides for two significant streams of revenue for the Department. One revenue stream is generated from "Bond Charges" imposed for the purpose of providing sufficient funds to pay "Bond Related Costs." Bond Charges are applied based on the aggregate amount of electric power sold to each customer by the Department and the applicable IOU, and, to the extent provided by final unappealable Commission orders, Electric Service Providers. Bond Related Costs include Bond debt service, Qualified Swap payments, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds. The Rate Agreement requires the Commission to impose Bond Charges sufficient to ensure that amounts on deposit in the Bond Charge Payment Account are adequate to pay all Bond Related Costs as they come due. Bond Charges are imposed upon customers within IOU service territories regardless of whether those customers purchase their energy supplies from the Department and/or IOUs or Electric Service Providers.

The second revenue stream is generated from "Power Charges" imposed on customers who buy power from the Department, and is designed to pay for "Department Costs," including the costs that the Department incurs to procure and deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements as specified by the Department.

An additional revenue stream for the payment of Department Costs is provided by components of cost responsibility surcharges imposed by the Commission on customers other than those who buy power from the Department--for example, Direct Access or Community Choice Aggregation customers. To the extent these cost responsibility surcharges are imposed and remitted to DWR, the Department's Retail Revenue Requirement (Power Charges to be collected from bundled customers) is lower. This 2006 Proposed Determination does not separately specify the sources of revenues to pay Department Costs, and accounts for all revenues as if they were Power Charges and included in the Retail Revenue Requirement.

Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in, and accounted for under, the Electric Power Fund established by the Department under the Act.

Revenues from Power Charges and related cost responsibility surcharges are deposited into an "Operating Account." Funds in the Operating Account are used to pay Department Costs and are

[3] California Public Utilities Commission, Decision 02-02-051, "Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources," adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

also transferred at least monthly on a priority basis to a “Priority Contract Account.” The Priority Contract Account is used to pay for the costs that the Department incurs under its Priority Long Term Power Contracts (“PLTPCs”), which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs (such as Bond debt service).

In addition, the Department funds an “Operating Reserve Account” to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges are deposited into a “Bond Charge Collection Account.” Funds in the Bond Charge Collection Account are transferred periodically to a “Bond Charge Payment Account.” Funds in the Bond Charge Payment Account may only be used to pay Bond Related Costs. Funds in the Bond Charge Collection Account may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs if and only if amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient. If the Bond Charge Collection Account is used to pay amounts due under PLTPCs, the Bond Charge Collection Account is to be replenished or reimbursed from amounts, when available, in the Operating Account.

These Bond Charge and Power Charge accounts are further described in Section D.

PRIOR PROCEEDINGS RELATING TO 2005 AND THE PROJECTED STARTING BALANCE FOR 2006

On September 9, 2004, the Department published its Proposed Determination of Revenue Requirements for 2005, consistent with the requirements of Sections 80110 and 80134 of the California Water Code and the Regulations, and provided information consistent with the requirements of the Rate Agreement.

On October 20, 2004, the Department issued a Notice of Additional Material to be relied on in determining its revenue requirements, and made such additional material upon which it intended to rely available to interested persons. In conjunction with the Notice of Additional Material, the comment period for the Department’s Proposed Determination was extended to October 27, 2004, allowing sufficient opportunity for interested persons to review and comment on the Proposed Determination and additional material.

During the period between September 9, 2004, and October 27, 2004, when comments were due, the Department responded to questions in an effort to assist interested persons in the review and understanding of the Proposed Determination and additional material.

On September 30, 2004, the Department received initial comments on the 2005 Proposed Determination from PG&E, SCE, and SDG&E. On October 27, 2004, additional comments were received from PG&E and SCE. On October 29, 2004, the Department received comments from the CPUC’s Energy Division. After a review of all comments, the consideration of preliminary actual operating results through September 30, 2004 (the 2005 Proposed Determination incorporated preliminary actual operating results through June 2004), and an analysis of Decision 04-08-050 (Order Implementing the Supplemental 2004 Determination, dated March 10, 2004), the Department made changes in the 2005 Proposed Determination, resulting in the Determination of Revenue Requirements for the period January 1, 2005 through December 31, 2005, which was published on November 4, 2004 and submitted to the Commission. The November 4, 2004 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, AB1X, the Regulations, Bond Indenture requirements and the Rate Agreement.

Thereafter, the Commission commenced hearings on the allocation of the 2005 revenue requirements among retail customers in the service territories of the IOUs. On March 17, 2005, in Decision 05-03-024, the Commission adopted an interim allocation of the Department's 2005 revenue requirements consistent with the permanent allocation methodology adopted in Decision 04-12-014 (Decision 04-12-014 was adopted on December 2, 2004, but applies retroactively to January 1, 2004).[4]

Concurrent with the adoption of the interim allocation, new information became available that changed the Department's projections of its revenue requirements for 2005. As a result, on February 28, 2005 the Department published its Proposed Revision to the 2005 Revenue Requirement Determination for the period January 1, 2005 through December 31, 2005.

On March 7, 2005, the Department received comments on proposed revisions to the 2005 Revenue Requirement Determination from PG&E and SCE. No comments were received from SDG&E. Following a detailed review of comments received by the PG&E and SCE, certain changes were incorporated and, on March 16, 2005, the Department published its Revised 2005 Determination, reflecting a reduction of $166 million to its 2005 revenue requirements (the cash basis revenue requirement presented in the November 4, 2004 Determination totaled $4.824 billion).

The Department prepared the Revised 2005 Determination under Section 516 of the Regulations to address the following matters:

- Updated actual Electric Power Fund operating results through December 31, 2004;
- El Paso Energy Settlement Agreement;
- Williams Energy Marketing & Trading Settlement Agreement; and
- Natural Gas Price Forecasts and Related Assumptions.

In addition, the Department revised the methodology employed to model the Bond Charge Payment Account required balance to take into account the difference between the actual historical variable rate component of total debt service and the variable interest rate funding level required by the Bond Indenture.

Additional detail related to the Revised 2005 Determination is provided in the Revised 2005 Determination itself, which is included as part of the administrative record supporting this 2006 Proposed Determination.

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[4] On January 13, 2005, the Commission adopted Decision 05-01-036, which grants a limited rehearing of Decision 04-012-014. A petition for modification of Decision 04-12-014 filed by SDG&E is also pending before the Commission.

On April 7, 2005, the CPUC adopted Decision 05-04-025, implementing an allocation of the Revised 2005 Determination consistent with the permanent allocation methodology adopted in Decision 04-12-014. This 2006 Proposed Determination is based in part on the Commission's implementation of the Revised 2005 Determination, resulting in a starting balance for the 2006 Revenue Requirement Period as projected herein.

In addition to these considerations, the Department distributed, via email, data requests to each IOU on April 18, 2005 in which clarification, comment or an update of various modeling assumptions and operational considerations was solicited. In these data requests, the Department referenced its forecasted data (for the 2006 and 2007 calendar years) provided in connection with the Revised 2005 Determination and asked each IOU to review and provide comment on any concerns with this data set. Each IOU's independent data review and compilation of specific comments/responses was scheduled for completion by May 8, 2005.

On May 6, 2005, the Department received PG&E's response to the aforementioned data request. On May 11, 2005, the Department received a supplemental data response from PG&E in which additional load data was provided. On May 13, 2005, the Department received SCE's response to the aforementioned data request, and on May 17, 2005, the Department received SDG&E's response to the aforementioned data request.

The information obtained from the IOUs, much of which is considered by each individual IOU as confidential and provided under a non-disclosure agreement, became the basis for the Department's analytical and forecasting efforts related to this 2006 Proposed Determination. The Department also considered other important criteria such as Commission Decisions and Bond Indenture requirements. The resulting data was incorporated into the PROSYM simulation model and the Financial Model, and became a part of the projections leading to this 2006 Proposed Determination.

Upon completion of the procedures set forth in the Regulations, the Department will determine its revenue requirements for the 2006 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2006 THROUGH DECEMBER 31, 2006

REVENUE REQUIREMENT DETERMINATION

For 2006, the Department's revenue requirements consist of Department Costs and Bond Related Costs, which are to be satisfied primarily by Power Charge Revenues and Bond Charge Revenues, respectively.

Department Costs include:

(1) Costs associated with power supply to be delivered under the Department's Priority Long-Term Power Contracts ("PLTPCs");

(2) Administrative and general expenses;

(3) Gas collateral costs; and

(4) Amounts required to maintain operating reserves as determined by the Department (see Table A-1).

Power Charge Accounts revenues include:

(1) Revenues from other power sales;

(2) Interest earnings on Power Charge Accounts; and

(3) Power Charge Revenues (including both Power Charge Revenues and CRS revenues from customers other than customers of the IOUs and DWR).

There are no provisions included in Department Costs for the procurement of the residual net short by the Department during 2006.

During 2006, the Department projects that it will incur the following Department Costs: (a) $4.543 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $36 million in administrative and general expenses; and (c) $46 million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a total revenue need of $4.625 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $193 million from the Department's share of surplus power sales revenues; (b) $24 million of interest earned on Power Charge Account balances; and (c) $4.408 billion from Power Charge Revenues and CRS revenues from customers other than customers of the IOUs and DWR.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2006 Revenue Requirement Period.

TABLE C-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)				
		2006 - Q1	2006 - Q2	2006 - Q3	2006 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	1,091	945	1,288	1,220	4,543
3	Administrative and General Expenses	9	9	9	9	36
4	Net Changes to Power Charge Account Balances	(35)	85	(72)	67	46
5	**Total Power Charge Accounts Expenses**	**1,065**	**1,039**	**1,225**	**1,296**	**4,625**
6	*Power Charge Accounts Revenues*					
7	Other Power Sales Revenues	60	45	30	58	193
8	Interest Earnings on Power Charge Account Balances	6	6	6	6	24
9	Total Power Charge Revenue Requirement[1]	998	988	1,189	1,232	4,408
10	**Total Power Charge Accounts Revenues**	**1,065**	**1,039**	**1,225**	**1,296**	**4,625**

[1]Represents the Department's Retail Revenue Requirement, except to the extent funded by surcharge revenues.

Bond Related Costs include:

(1) Debt service on the Bonds (including related Qualified Swap payments); and

(2) Changes to Bond Charge Account balances.

Bond Charge Accounts revenues include:

(1) Interest earned on Bond Charge Account balances; and

(2) Bond Charge Revenues (including CRS revenues from customers other than customers of the IOUs and DWR).

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2006 Revenue Requirement Period.

TABLE C-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)				
		2006 - Q1	**2006 - Q2**	**2006 - Q3**	**2006 - Q4**	**Total**
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	35	637	36	219	926
3	Net Changes to Bond Charge Account Balances	168	(423)	215	34	(6)
4	**Total Bond Charge Accounts Expenses**	**203**	**214**	**251**	**253**	**921**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	4	20	3	19	46
7	Retail Customer Bond Charge Revenue Requirement	199	194	248	234	874
8	**Total Bond Charge Accounts Revenues**	**203**	**214**	**251**	**253**	**921**

During 2006, the Department projects that it will incur the following Bond Related Costs: (a) $926 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements in connection with the Bonds, and (b) $(6) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $921 million.

Funds to meet these requirements are provided from (a) $46 million in interest earned on Bond Charge Account balances, and (b) $874 million from Bond Charge Revenues (including CRS revenues from customers other than customers of the IOUs and DWR). There are no projected net transfers from Power Charge Accounts.

In aggregate, the Department's total cash basis expenses are projected to be $5.506 billion. Revenues from interest earned and other power sales are projected to be $264 million, and net changes in fund balances are projected to be $40 million, resulting in proposed, combined customer revenue requirements of $5.282 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2006 REVENUE REQUIREMENT PERIOD

This 2006 Proposed Determination is based on a number of assumptions regarding retail customer load, demand side management and conservation, power supply, natural gas prices, off-system sales, administrative and general expenses as well as other considerations affecting the Department's revenues and expenses.

IOU LOAD FORECASTS

The Department obtained the most recent customer load forecasts from each IOU. PG&E and SDG&E's forecasts were developed in January 2005. SCE's forecast was developed in December 2004. Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by the end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified to account for current trends, judgment, or other events not specifically addressed in the models. In addition, the forecasts received from the IOUs were compared with other relevant information including recorded IOU sales data, utility expected growth factors, and forecasts prepared by the California Energy Commission ("CEC").

Table D-1 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this 2006 Proposed Determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. SCE derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), and SDG&E relied on a DRI forecast of economic trends in its service area.

TABLE D-1
MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS OF THE INVESTOR-OWNED UTILITIES

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth	1.4%	1.1%	1.3%
Number of Households	1.4%	1.3%	1.4%
Non-Farm Employment	1.9%	0.9%	1.5%
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: Assumptions provided by forecasting group of each IOU in May 2006.

A loss factor was applied to the IOU estimates of sales at customer meters to obtain the total amount of necessary energy to meet customer electricity requirements. The loss factors utilized in developing the estimate of the electricity requirements are presented in Table D-2.

TABLE D-2
LOSS FACTORS UTILIZED

Utility	Distribution	Transmission	Total
PG&E	6.0%	1.5%	7.5%
SCE	5.3%	3.3%	8.6%
SDG&E	4.3%	2.0%	6.3%

HOURLY LOAD SHAPES

The Department's retail revenue requirements are determined, in part, based on projections of hourly energy dispatches from long-term power contracts, as well as other generating resources, including utility-retained generation, required to serve retail customer load. To facilitate its modeling efforts, the Department "shapes" the load forecasts provided by each IOU to account for hourly variations in retail customer demand. The resultant hourly load profile is utilized in the Department's electric market simulation to derive hourly energy dispatches required to serve retail customer load. To construct the hourly load shapes included in its market simulation, the Department utilized total retail and Direct Access hourly load shapes provided by each of the IOUs. Hourly energy and peak usage was estimated by applying a percentage of sales in each hour to annual energy estimates provided by the IOUs.

SELF-GENERATION

Projected self-generation volumes are incorporated in the IOU load forecasts. Self-generation describes load that supplies all or a portion of its energy requirements from on-site or "over-the-fence" generation. Self-generation projections within each IOU service territory were determined by the Department based on a range of factors including: (a) self-generation and/or renewable resource incentive programs and initiatives administered by the CEC, the Commission, the California Consumer Power and Conservation Financing Authority ("CPA"), and the California Independent System Operator ("CAISO"); (b) recent price increases, cost responsibility surcharges, the suspension of Direct Access, increased concerns over service reliability, and ongoing efforts to standardize interconnection requirements through the Commission's Rule 21 proceedings; and (c) potential barriers and market restraints to the expansion of self-generation. The forecasted self-generation is incorporated in the IOU forecasts. Therefore, the estimate of self-generation does not result in a net reduction in energy and demand requirements compared with the forecasts prepared by the IOUs. Trends in self-generation capacity will be monitored and these assumptions will be revisited if warranted.

DIRECT ACCESS

The Commission has suspended the right of bundled load to elect direct access service after September 20, 2001. Electric end-users who elected to acquire electricity supplies from alternative providers on or before September 20, 2001 and have not since returned to bundled service continue to be eligible for direct access service. Decision 02-03-055 prohibits the IOUs from accepting any new direct access service requests not already approved by the Commission, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service, and contemplates the establishment of a surcharge on direct access customers. The direct access surcharge is intended to prevent cost shifting as a result of direct access migration prior to September 20, 2001.[5]

On February 19, 2004, the Commission issued Decision 04-02-042 which allows current direct access customers to increase load at one or more locations, provided that net load by the same customer does not increase within a utility's service territory. This provision is intended to maintain the "standstill principle" adopted in Decision 02-03-055, while accounting for "normal changes in business operations."[6] In Decision 04-07-025, the Commission clarified rules governing load growth for existing direct access accounts.

The Department's direct access estimates, which are based on data provided by PG&E and SDG&E in January 2005, and SCE in December 2004, are included in Table D-3. Based on the conditions imposed by applicable CPUC Decisions, the Department believes that direct access will continue at or near such levels in 2006. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes, for any changes that would require action by the Department.

TABLE D-3
DIRECT ACCESS PERCENT OF LOAD[7]

	Percentage of Total Load
Pacific Gas and Electric Company	11.1%
Southern California Edison Company	13.1%
San Diego Gas and Electric Company	18.8%
Statewide	**12.8%**

OTHER DEPARTING LOAD

Other departing load includes relocation of load or annexation of load to a municipality ("municipal departing load" or "MDL"), and Community Choice Aggregation ("CCA"). Municipal departing load refers to load that either relocates to, or resides on land that is annexed by, a California municipality that operates its own electric utility. CCA refers to the ability of communities or public entities to aggregate load and procure all or a portion of their power requirements independent of the IOUs. Assembly Bill 117, adopted in 2002, modified the Public Utilities Code to allow local governments "…to elect to combine the loads of its residents, businesses, and municipal facilities in a community-wide electric buyers' program."[8]

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[5] See discussion under Direct Access Surcharge Revenues, below.
[6] Decision 04-02-042, Finding of Fact 4.
[7] Figures in Table D-3 represent direct access as a percentage of total retail load for 2006. These percentages correspond to direct access loads forecast by the IOUs in 2005. The Department assumes that direct access load will remain constant from 2006 to 2007.
[8] Public Utilities Code, Section 331.1(a).

In 2006, the Department expects the total load from self-generation (see "Self-Generation" above), MDL, and CCA to amount to less than 2% of total retail sales. Unlike direct access, the growth of self-generation, MDL, and CCA is not expressly limited by Commission decision. However, the Commission has imposed on certain classes of self-generation, MDL, and CCA customers a surcharge or other mechanism to prevent cost shifting similar to the cost responsibility surcharge imposed on direct access load. Therefore, the Department anticipates that in the future it may collect a portion of its revenue requirement from self-generation, MDL, and CCA customers.

In 2007 and beyond, the amount of departing load and CCA could increase significantly. While the permitting process and the relatively high capital costs of installing micro-turbines or other on-site generation will curb the growth of self-generation, and MDL is expected to follow historical growth trends, the opportunity for whole communities to aggregate load and procure power at competitive prices under CCA could lead to substantial reductions in bundled sales volumes. The Department is closely monitoring Rulemaking 03-10-003, establishing processes, procedures, and surcharges for CCA loads. Based on the requirements of AB117 and the progress of Rulemaking 03-10-003, the Department does not expect CCA load to rise to substantial levels before 2007. DWR does not anticipate receiving a meaningful level of revenues from CCA customers during 2006.

ESTIMATED ENERGY REQUIREMENTS

Each of the aforementioned considerations, including hourly load shape, self-generation, direct access and other departing load are incorporated in the determination of the amount of energy consumed by the retail customers of the Utilities. Those customers are also the customers of the Department.

Table D-4 shows the estimated gigawatt hours of the expected energy requirements of each IOU's customers during 2006.

TABLE D-4
ESTIMATED ENERGY REQUIREMENTS

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company	
Energy Requirements	89,689
Less Direct Access	9,931
Energy Requirements After Adjustments[9]	79,758
Southern California Edison Company	
Energy Requirements	94,577
Less Direct Access	12,377
Energy Requirements After Adjustments	82,200
San Diego Gas and Electric Company	
Energy Requirements	21,215
Less Direct Access	3,777
Energy Requirements After Adjustments	17,438
All Investor Owned Utilities	
Energy Requirements	205,481
Less Direct Access	26,085
Energy Requirements After Adjustments	179,396

[1]All values presented include transmission and distribution losses.

POWER SUPPLY RELATED ASSUMPTIONS

Three types of power supplies needed to meet the requirements of each IOU were considered by the Department in this 2006 Proposed Determination: (a) Utility supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU.[10]

Table D-5 below shows, for the 2006 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation retained by the three IOUs,[11] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

[9] For each of the three IOUs, these amounts are intended to represent energy requirements that must be met by the electric generating resources of the IOU, power purchases of the IOU or power purchases of the Department under the PLTPCs.

[10] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its Proposed Determination for the 2006 Revenue Requirement Period. For purposes of the 2006 Proposed Determination, the residual net short for each IOU equals the projected amount of wholesale energy to be procured by such IOU on behalf of ratepayers in its service area.

[11] For purposes of this Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QF's") and other bilateral contracts.

TABLE D-5
ESTIMATED NET SHORT ENERGY, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
All Investor Owned Utilities	
Energy Requirements After Adjustments	179,396
Supply from Utility Resources	121,354
Net Short	58,042
Supply from the Department's Long-Term Power Contracts	57,280
Off-System Sales	(9,543)
Residual Net Short (Surplus)	10,305

Table D-6 shows, on a quarterly basis for the 2006 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

TABLE D-6
NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2006[1]

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWh)
Q1-2006	11,972	13,772	$ 1,040	(2,950)	$ (170)	1,150
Q2-2006	12,485	12,948	$ 1,033	(2,506)	$ (112)	2,043
Q3-2006	20,438	16,013	$ 1,337	(1,162)	$ (81)	5,587
Q4-2006	13,146	14,547	$ 1,153	(2,925)	$ (201)	1,525
Total	58,042	57,280	$ 4,563	(9,543)	$ (564)	10,305

[1]All costs and revenues are presented on an accrual basis.

UTILITY SUPPLIED RESOURCES

The Department reviewed each utility's 2006 forecast of utility owned generation, qualifying facility ("QF") contract generation, and bilateral contract generation for consistency with the Department's own energy dispatch forecast. Where necessary, the Department updated its assumptions concerning QF contract terms and expiration dates, outage schedules, and net dependable resource capacity, among others, to reflect current details related to each IOU's resource portfolio.

HYDRO CONDITION ASSUMPTIONS

Normal hydrologic conditions are assumed for both California and the Pacific Northwest during 2006 and 2007. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the 2005 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2006 Revenue Requirement Period.

CONTRACT ASSUMPTIONS

During the 2006 Revenue Requirement Period, approximately 57,000 GWhs of energy is projected to be supplied to retail electric customers of the IOUs through the Department's long-term power contracts. The terms and conditions of each contract have been reflected in the Department's market simulation, resulting in a projection of contract-specific, hourly energy dispatches to meet the projected energy requirements of each Utility's retail customers. The terms and conditions incorporated in the Department's market simulation include, among other details, must-take energy volumes and dispatchable contract capacities, contract heat rates and unit outage rates as well as scheduling limitations. During market simulation, all energy dispatches from the Department's dispatchable long-term power contracts are executed based on economic considerations to achieve the lowest possible total cost of power to IOU customers. In general, each incremental generating unit is dispatched only if the incremental cost of generating an additional MWh from that unit is less than the cost of market clearing prices.

Table D-7 provides a listing of all of the long-term power contracts that will be operational during the 2006 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated. This list includes a contract with the Kings River Conservation District, which the Department signed in December 2002 relative to approximately 90 MW of capacity for 10 years, currently expected to begin in June 2005. Regarding the Amended and Restated Demand Reserves Purchase Agreement with the California Power Conservation and Financing Authority, projected costs for the 2006 Revenue Requirement Period are $12 million. Detailed contract terms can be found on the CERS website, http://cers.water.ca.gov.

TABLE D-7
LONG-TERM POWER CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Allegheny Energy Supply Company, LLC	3/23/2001 Renegotiated 6/10/03	1/1/2006	12/31/2011	800	SCE
Alliance Colton LLC	4/23/2001 Renegotiated on 9/19/02	8/1/2001	12/31/2010	80	SCE
CalPeak Power--Panoche LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	50.8	PG&E
CalPeak Power--Vaca Dixon LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	50.8	PG&E
CalPeak Power--El Cajon LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	52	SDG&E
CalPeak Power--Border LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	51.3	SDG&E
CalPeak Power--Enterprise LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	48	SDG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Calpine Energy Services, L.P. (Firm)	2/6/2001 Renegotiated on 4/22/02	1/1/2004	12/31/2009	1000	PG&E
Calpine Energy Services, L.P. (Long Term Commodity Sale)	2/26/2001 Renegotiated on 4/22/02	7/1/2002	12/31/2009	1000	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated on 4/22/02	8/1/2002	7/31/2011	495	PG&E
Calpine Energy Services, L.P. (North San Jose Project)	6/11/2001 Renegotiated on 4/22/02	3/5/2003	3/5/2006	184	PG&E
Clearwood Electric Company, LLC	6/22/2001 Renegotiated on 7/2/04	Upon COD, est. 1/2007	12/31/2012	30	PG&E
Coral Power, LLC	5/24/2001	1/1/2006	6/30/2010	400	PG&E
"	"	7/1/2010	6/30/2012	100	PG&E
"	"	7/1/2002	6/30/2012	100	PG&E
"	"	7/1/2003	6/30/2012	175	PG&E
"	"	7/1/2004	6/30/2012	175	PG&E
GWF Energy LLC	5/11/2001 Renegotiated on 8/22/02	9/6/2001	12/31/2011	94.8	PG&E
"	"	7/1/2002	12/31/2011	96.7	PG&E
"	"	6/01/2003	10/31/2012	170.5	PG&E
High Desert Power Project	3/9/2001 Renegotiated on 4/22/02	4/22/2003	3/31/2011	Up to 840	SCE
Kings River Conservation District	12/31/2002 Renegotiated 8/18/04	Upon COD, est. 6/2005	Est. 5/31/2015	Est. 92	Est. PG&E
Mountain View Power Partners, LLC	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE
PacifiCorp	7/6/2001	7/1/2004	6/30/2011	300	PG&E
City/County of San Francisco	12/30/2002	Upon COD, est. 6/2007	Est. 5/31/2017	Est. 180	Est. PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200; drops to 800 in Mar-May of 2004-2007	SCE

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	SCE
Soledad Energy LLC	4/28/2001; terminated on 3/27/02; Revision Executed on 6/27/02	9/09/2002	10/31/2006	13	PG&E
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/2003	6/30/2012	572	SDG&E
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated on 12/17/02	8/20/2001	10/31/2011	21.3	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.5	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	PG&E
Whitewater Energy Corp. (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Whitewater Energy Corp. (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E
Williams Energy Marketing & Trading	2/16/2001 Renegotiated on 11/11/02	7/1/2003	12/31/2007	200	SDG&E
"	"	1/1/2006	12/31/2007	450	SDG&E
"	"	1/1/2008	12/31/2010	275	SDG&E
"	"	7/1/2003	12/31/2010	50	SDG&E
"	"	7/1/2003	12/31/2007	1175	SDG&E
"	"	1/1/2008	12/31/2010	1045	SDG&E

The Department, in cooperation with representatives of the Attorney General's office, the Commission's staff, staff of the Electricity Oversight Board, and representatives of the Governor's staff, has continued its efforts to modify terms and conditions of the Department’s long-term power contracts consistent with the requirements of the Act. Three of the remaining original contracts have yet to be renegotiated from their original terms.

CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES

The Power Charge component of the revenue requirement is directly related to the costs of power supplied under the Department's long-term power contracts. In considering changes to the contracts to modify its revenue requirements, the Department can (1) continue to use its contracts in their present form, (2) seek to modify the contracts through bilateral renegotiation with its counterparties, or (3) terminate the contracts.

The Department has renegotiated 19 of the remaining original contracts entered into in 2001 and has terminated five additional contracts for cause. The Department has continued efforts to renegotiate additional contracts. The Department continues to monitor its contracts and determine if there are opportunities for bilateral renegotiation, which could lead to more favorable power supply terms and costs.

Theoretically, the Department could terminate one or more of its contracts. The terms of each of the Department's contracts provide that if the contract is terminated for reasons other than breach or default by the power-supplying counterparty to the contract, the Department is obligated to pay the entire remaining estimated value of the contract. Any such termination other than for an uncured default or breach by the seller would likely increase the revenue requirement due to timing implications of the payments to the counterparty. In addition, energy no longer supplied by DWR would need to be replaced by the investor-owned utilities in either the short-term market or new long-term power contracts from other suppliers. For this reason, under present market conditions and terms of the contracts, the Department does not believe that termination of any of the contracts would result in a net savings in the revenue requirement or overall ratepayer costs.

COST RESPONSIBILITY SURCHARGE

In a series of decisions, the Commission has ordered certain classes of direct access, municipal and customer generating departing load, and community choice aggregation customers to pay a Cost Responsibility Surcharge ("CRS") related to historical stranded costs and ongoing costs. Included in the CRS is the DWR Bond Charge, which is assessed to pay debt service associated with the Department's 2002 issuance of revenue bonds, and a DWR power charge component, which pays a portion of the costs of the DWR power portfolio.

Payments by direct access and other departing load of the DWR Bond Charge and the DWR power charge component flow to the Department through Commission established rates on total usage by departed load. These revenues reduce one-for-one the bundled customer responsibility for DWR Bond Related Costs and Department Costs. DWR power charge component collections from direct access, in particular, are limited by a maximum collections rate, or cap, established by the Commission. Differences in the collection and accrual rate for the DWR power charge component of the CRS are carried forward to collect in future periods when the current period collections rate is less than the accrual rate.

The CRS does not affect Department power costs. The CRS creates a revenue offset to bundled customers for a portion of the costs associated with the bundled customer portfolio. With the exception of minor differences in the timing of revenue receipt between bundled customers and non-exempt direct access and other departing load customers, the revenue requirement in total is unaffected by the amount of the CRS.

SALES OF EXCESS ENERGY ASSUMPTIONS

As with any retail provider of energy, the Department and IOUs together, from time to time, purchase more energy than is needed to serve their retail customers. In general, these additional purchases result from differences between projected and actual IOU load. This excess energy is sold in wholesale markets by the IOUs under the current operating arrangements governing administration, operation and dispatch of DWR's contracts. On occasion, the price obtained for surplus power sales will be less than the price paid for power. However, these minimal losses are an expected incident of appropriate portfolio management, in that losses on sales from over-procurement are on average less than the costs associated with spot market purchases when there has been under-procurement. The income from such sales is used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers.

On September 19, 2002, the Commission issued Decision 02-09-053, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-five long-term power contracts to a specific IOU. Decision 02-09-053 also determined that income from the sale of excess energy ("off-system sales") would be shared on a pro-rata basis between the Department and the IOUs.

Projected revenue shares from the sale of excess energy, both the Department's and total IOU, are provided below in Table D-8.

TABLE D-8
PROJECTED SALE OF EXCESS ENERGY[1]

	DWR Volume (GWh)	IOU Volume (GWh)	Total Volume (GWh)	DWR Revenue (Millions of Dollars)	IOU Revenue (Millions of Dollars)	Total Revenue (Millions of Dollars)	Weighted Average Price ($/MWh)
Q1-2006	881	2,069	2,950	$ 52	$ 119	$ 170	$ 58
Q2-2006	728	1,778	2,506	$ 34	$ 78	$ 112	$ 45
Q3-2006	546	616	1,162	$ 42	$ 39	$ 81	$ 70
Q4-2006	953	1,972	2,925	$ 67	$ 135	$ 201	$ 69
Total	3,108	6,435	9,543	$ 194	$ 370	$ 564	$ 59

[1]All revenues presented on an accrual basis.

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each long-term power contract identified in Table D-7 has been reviewed by the Department to determine the costs that will impact its revenue requirements during 2006. All applicable costs are reflected in the Department's electric market simulation along with previously noted operational considerations. The types of costs included in the Department's contract-specific projections include, but are not limited to, fixed energy, capacity, fixed operation and maintenance, variable operation and maintenance, scheduling coordinator fees, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $4.543 billion for the 2006 Revenue Requirement Period, as noted in Table D-6. Natural gas costs represent a significant component of the Department's total energy costs and are discussed below in greater detail.

For informational purposes, Table D-9 shows, for the 2006 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

TABLE D-9
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Power Contracts
Quarter 1 – 2006	$76
Quarter 2 – 2006	$80
Quarter 3 – 2006	$83
Quarter 4 – 2006	$79

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting the 2006 Proposed Determination is based on a forecast prepared by Navigant Consulting, Inc. ("NCI") using the Gas Market Data and Forecasting System owned by Energy and Environmental Analysis, Inc. ("EEA"), with certain assumptions specified by NCI. These assumptions included the timing of major gas pipeline capacity changes, the prices of crude oil and coal, the timing and magnitude of certain liquefied natural gas ("LNG") capacities, and imports and exports. The EEA model uses a structural, network simulation of the natural gas markets in the U.S. and Canada to solve for natural gas production volumes, gas demand by sector, gas flows, storage activity, and gas prices at a number of market "nodes" in North America.

The initial model results are then reviewed by NCI and compared with the NYMEX forward price. For the 2006 gas price forecast, a 0.996 factor was applied to the raw Henry Hub price point to bring the forecasted prices generally in line with short-term market conditions as reflected on the NYMEX. Any adjustments to the model output were only applied to the gas price series for the Henry Hub node. The proportional relationships between the prices forecasted for the Henry Hub and the other market nodes were maintained.

The right to use the EEA model price output was obtained by NCI under contract with EEA, and this model is used by NCI for all of its electric market assignments.[12] The Department prefers to use the EEA model because it simulates of the fundamental market dynamics that are not reflected in forward gas prices, particularly those beyond 12-18 months. The base case gas forecast supporting the 2006 Revenue Requirement Determination was prepared based on the NCI-EEA model run dated March 2005. The DWR forecast will be run twice annually or more often as required to reflect revised market conditions and assumptions.

[12] Prior forecasts for DWR had been prepared by NCI based upon a proprietary forecast model.

Compared to the base case forecast in the 2005 Revised Determination, prices in the base case forecast in this 2006 Proposed Determination are shown in Table D-10.

TABLE D-10
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2005	2006	2007
Gas Price Forecast 2006 Proposed Determination	$7.34	$7.48	$6.78
Gas Price Forecast Revised 2005 Determination	$6.38	$5.75	$5.54
Difference	$0.96	$1.73	$1.24

Table D-11 below lists the natural gas prices by month for 2006 and 2007 at two key pricing hub locations: PG&E Citygate and the Southern California Border.

TABLE D-11
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		PG&E Citygate	
	2006	2007	2006	2007
January	$6.85	$7.42	$6.87	$7.49
February	$6.46	$7.07	$6.50	$7.13
March	$6.00	$6.70	$6.05	$6.78
April	$6.58	$6.01	$6.64	$6.10
May	$8.57	$6.25	$8.65	$6.36
June	$7.41	$5.99	$7.48	$6.07
July	$7.53	$6.87	$7.61	$6.98
August	$7.18	$6.90	$7.24	$6.98
September	$7.78	$7.03	$7.85	$7.12
October	$7.57	$6.11	$7.67	$6.22
November	$7.65	$6.82	$7.80	$6.99
December	$7.82	$6.94	$7.92	$7.04
Annual Average	**$7.28**	**$6.68**	**$7.36**	**$6.77**

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $36 million consist of $33 million for appropriated budget expenditures and $3 million for consulting services for development and monitoring of the revenue requirements, litigation support, and financial advisory services for managing the $11 billion debt portfolio and related reserves.

The $33 million for calendar year 2006 appropriated budget expenditures is based on one-half of the proposed 2005-2006 fiscal year budget and one-half of the anticipated budget for fiscal year 2006-2007. The amount includes funds for labor and benefits, professional services costs and pro rata charges for services provided to the power supply program by other State agencies.

GAS COLLATERAL COSTS

For the 2006 Revenue Requirement Period, the Department has again calculated cash collateral requirements in connection with gas purchases. The purpose of these amounts is to provide funds to enable the hedging activity of the IOUs in connection with the operation of the Department's power contracts. As in the past, the Department calculated initial NYMEX margin based upon current listed collateral requirements of the NYMEX, to secure futures on the highest seven-months of fuels requirements. To determine sensitivity for the time period selected to calculate the collateral requirements, a separate calculation assuming all fuel volumes were hedged was also done. Margin requirements of the NYMEX exchange are listed by the exchange. The margins are exchange requirements based upon a fixed price per futures contract and also, separately, upon fixed prices per basis contract. It is recognized that any hedges put in place by the IOU's will use both options and fixed price instruments and since options premium costs vary significantly due to the timing of the option purchase (and for how far forward), the collateral amount assumed all hedges were for fixed prices at NYMEX exchange costs.

In order to determine a total margin cost, anticipated fuel volumes from June through December 2006 were utilized. These anticipated fuel volumes are determined through the use of the production simulation analysis supporting this 2006 Proposed Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from June through December 2006 would be $100 million. The 2006 Proposed Determination assumes that the amount required in excess of the balance projected to be in the Department's hedging account is zero. The Department intends to base its final determination on additional information provided by the IOUs during the Department's administrative process and by the balance in DWR's hedging account as of September 30, 2005.

Fuel price volatility, as well as mitigating hedging activities, is a key component in calculating required operating reserves in this 2006 Proposed Determination.

The estimate for 2006 is over 20% higher than the 2005 collateral requirement of $83 million included in the Revised 2005 Determination. The increase in margin requirements is due almost entirely to increased fuel volumes forecast to be required by the IOUs. Simulated fuel volumes for PG&E in particular have been forecast to increase from a total fuel volume requirement in 2005 of 11,853 Bcf (including the PacifiCorp Contract) in the 2005 Revenue Requirement Determination to 40,819 Bcf for 2006 in this 2006 Proposed Determination, an increase of 345%. Between the three IOUs, fuel requirements in 2006 compared to 2005 are expected to increase from 168,857 Bcf to 204,165 Bcf (not including the Williams contract), or an increase of 21%.

EL PASO ENERGY SETTLEMENT AGREEMENT

On June 24, 2003, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with El Paso Energy that resulted in the Department's receipt of nearly

$161 million during the 2004 Revenue Requirement Period (June 28, 2004). The receipt of $161 million was a combination of several components specified within the Master Settlement Agreement, which included nearly $109 million related to proceeds from El Paso Energy's requisite corporate stock sale, nearly $50 million in monthly contract price reductions and associated interest for the period beginning July 2003 through June 2004, and $2.1 million to reimburse the Department for attorneys' fees and costs related to this settlement. Amendment #1 to the El Paso power purchase agreement also provides for price reductions from May 2004 through the contract's expiration in December 2005, yielding a further benefit of $75 million in contract cost reductions.

In addition, semiannual cash payments were scheduled to be made in the amount of $5.4 million and were to be paid by El Paso Energy to the Department each January and July for the next 20 years (a total of approximately $209 million over this twenty year period), ending with a final payment in January 2024. However, under the terms of the settlement agreement El Paso Energy elected to prepay its remaining settlement obligations, resulting in the Department's receipt of $108 million on May 11, 2005. El Paso's prepayment of these settlement funds relieves its aforementioned obligation to issue semiannual cash payments to the Department. For the purposes of this 2006 Proposed Determination, the Department has reflected this receipt in its starting account balance for the 2006 Revenue Requirement Period.

Prior to El Paso's prepayment of its settlement obligations, the Department also received El Paso's scheduled semiannual payments including $5.5 million received by the Department on April 7, 2005. The receipts are reflected in the projected starting balance for the 2006 Revenue Requirement Period.

WILLIAMS ENERGY MARKETING & TRADING SETTLEMENT AGREEMENT

On November 11, 2002, the State of California, Office of the Attorney General, executed a Settlement Agreement with Williams Energy Marketing and Trading ("Williams") that resulted in the renegotiation of the original Power Purchase Agreements between the Department and Williams as well as the development of a Natural Gas Purchase Contract between the Department and Williams (natural gas deliveries began on January 1, 2004). On October 2, 2003, the CPUC issued Decision 03-10-016, which allocated fuel volumes related to the Williams Natural Gas Purchase Contract between SCE (62% in 2006) and SDG&E (38% in 2006).

During the 2006 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $59 million, based on the difference between the contract fuel price of $3.96 and the Department's projected average annual fuel price of $7.28. The projected power cost savings of $59 million is reflected in this 2006 Proposed Determination as a negative Extraordinary Contract Expense, as displayed above in Table A-1. Projected benefits have been allocated among the Department's power costs from long-term contracts administered by SCE and SDG&E in the ratio reflected in Decision 03-10-016.

MIRANT CORPORATION SETTLEMENT AGREEMENT

On January 14, 2005, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with Mirant Corporation that will result in the Department's receipt of nearly $76 million during the 2005 Revenue Requirement Period. The State's settlement with Mirant Corporation resolves claims related to energy overcharges against California ratepayers during 2000 and 2001. The settlement was approved by the Federal Energy Regulatory Commission (FERC) on April 13, 2005. The receipt of $76 million is projected to occur during June 2005. For the purposes of this 2006 Proposed Determination, the Department has reflected this receipt in its starting account balance for the 2006 Revenue Requirement Period. Additional amounts are expected to be received from Mirant Corporation at various dates in the future, but the amounts and timing of the future receipts are dependent on the emergence of Mirant Corporation from bankruptcy and the completion of additional FERC proceedings. Therefore, no additional amounts have been incorporated into this 2006 Proposed Determination.

FINANCING RELATED ASSUMPTIONS

In October and November 2002, the Department issued $11.263 billion of Power Supply Revenue Bonds. The primary uses of net Bond proceeds were to (a) repay the then-outstanding balance of the $4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately $6.1 billion advanced to the Department for 2001 power purchases and interest that had accrued on the General Fund advances, and (c) fund reserves required to complete the bond financing.

The details of the Bond financing structure were made public in connection with the Department's 2003 Revenue Requirement filing and are described in the Bond Indenture and the Supplemental Bond Indentures for each series of Bonds.

For purposes of calculating the interest earnings on all account balances, the Department assumes a 4.0 percent rate for the Debt Service Reserve Account (reflecting the Department's investment agreements) and a 2.0 percent earnings rate for all other accounts during the 2006 Revenue Requirement Period.

The Department projects that the amount of Bond Charge Revenues required for the 2006 Revenue Requirement Period will be $874 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

The Rate Agreement and Summary of Material Terms with all applicable addenda are reflected in the Bond Indenture. The following is a description of the funds and accounts that are required as part of the Bond program.

Revenues are held in and accounted for in the Electric Power Fund established under AB1X. The Bond Indenture established two sets of accounts for Revenues within the Electric Power Fund. In the following description of accounts and the flow of funds, capitalized terms refer to terms that are further defined in the Indenture.

One set of accounts is primarily for the deposit of Power Charge Revenues and the payment of Operating Expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the "Power Charge Accounts"):

- The Operating Account,
- The Priority Contract Account,
- The Operating Reserve Account, and
- The Administrative Cost Account.

The other set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the "Bond Charge Accounts"):

- The Bond Charge Collection Account,
- The Bond Charge Payment Account, and
- The Debt Service Reserve Account.

The Bond Indenture requires all Bond Charge Revenues to be deposited in the Bond Charge Collection Account and all Power Charge Revenues and other Revenues (other than Bond Charge Revenues) to be deposited in the Operating Account.

OPERATING ACCOUNT

The Department has covenanted in the Bond Indenture to include in its revenue requirements amounts estimated to be sufficient to cause the amount on deposit in the Operating Account at all times during any calendar month to equal the Minimum Operating Expense Available Balance ("MOEAB"). The Bond Indenture leaves to the Department the determination as to how far into the future this minimum test of sufficiency should be met. Moreover, the covenant concerns the minimum amount required to be projected to be on deposit, and leaves to the Department the determination as to what total reserves are appropriate or required in the fulfillment of its duties under Section 80134 of the Act (See Section B "Background—The Act").

The MOEAB is to be determined by the Department at the time of each revenue requirement determination and, when the Department is not procuring the residual net short, is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e., "stress cases").

For the purposes of this 2006 Proposed Determination, the MOEAB is determined to be $354 million. The Department projects to exceed the MOEAB at all times during 2006. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination".

PRIORITY CONTRACT ACCOUNT

The Priority Contract Account is used to pay the costs the Department incurs under its Priority Long Term Power Contracts, which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs. On or before the fifth Business Day of each month, the Department is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

For the 2006 Revenue Requirement Period it is projected that the Priority Contract Account will have sufficient funds available from the Operating Account, and that no transfer from Bond Charge Collection Account to the Priority Contract Account will be required.

OPERATING RESERVE ACCOUNT

The Operating Reserve Account Requirement ("ORAR") is to be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) 12 percent of the Department's projected annual Operating Expenses provided, however, that the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., "stress cases").

Based on the "stress" operating conditions (later described in the "Sensitivity Analysis" portion of Section D), the ORAR for the 2006 Revenue Requirement Period is determined by the Department to be $823 million, reflecting the aggregate amount by which projected Operating Expenses exceed Power Charge Revenues during the seven consecutive calendar months beginning July 2006 through and including January 2007.

BOND CHARGE COLLECTION ACCOUNT

All Bond Charge revenues will be deposited in the Bond Charge Collection Account. Subject to the prior claim on revenues in the Bond Charge Collection Account for the payment of Priority Contract Costs, on or before the last Business Day of each month, the Department is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds and all other Bond Related Costs) estimated to accrue or to be due and payable during the next succeeding three calendar months.

The minimum balance to be maintained from time to time within the Bond Charge Collection Account is determined to be an amount equal to one month's required deposit to the Bond Charge Payment Account. As required by the Bond Indenture, the Department assumes interest costs on unhedged Variable Rate Bonds during the 2006 Revenue Requirement Period at 4.0 percent for the purpose of calculating required deposits to the Bond Charge Payment Account. For the 2006 Revenue Requirement Period, the minimum account balance amount ranges from $77 to $79 million.

BOND CHARGE PAYMENT ACCOUNT

The Bond Charge Payment Account is calculated as an amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month. The Department assumes interest costs on unhedged Variable Rate Bonds during the 2006 Revenue Requirement Period at 4.0 percent for the purpose of calculating debt service accruals in the Bond Charge Payment Account. For the 2006 Revenue Requirement Period, the minimum account balance amount ranges from $238 to $849 million.

DEBT SERVICE RESERVE ACCOUNT

The "Debt Service Reserve Requirement" is an amount equal to maximum aggregate annual debt service on all outstanding Bonds, determined in accordance with the Bond Indenture. The Debt Service Reserve Account is required by the Bond Indenture to be funded in the amount of the Debt Service Reserve Requirement, initially with proceeds from the sale of the Bonds (or Alternate Debt Service Reserve Account Deposits referred to below, or a combination of both) and subsequently maintained and replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues.

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been outstanding, or (b) 4.0 percent. For the 2006 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.0 percent.

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations. The Department is not currently assuming the use of Alternate Debt Service Reserve Account Deposits.

For the 2006 Revenue Requirement Period, the Debt Service Reserve Requirement is determined to be $927 million.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the Commission no less than once each year, thereby ensuring that Bond Charges and Power Charges are adequate to meet financial obligations associated with the Bonds and the power supply program. From the date the Department first initiates any necessary revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, file and initiate the Commission process regarding the new revenue requirement and allocation of costs among customers, and finally begin receiving the modified level of revenue. In order to ensure its ability to meet its financial obligations during this seven month lag period, the Department must maintain reserves that are adequate to meet normal anticipated expenses, unexpected variations in these expenses, and/or reductions in revenue receipts resulting from factors beyond the Department's control. The determination of reserve levels is made by the Department considering such factors as the potential variations in revenue receipts and power supply program expenses, changes in key variables affecting customer energy requirements, URG production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of cash flow projections based on changes in certain key expense and operating assumptions ("Stress Cases"). The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, a market simulation was performed to generate revised net short requirements and associated power supply costs. These revised forecasts were used to generate revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the "Base Case").

The Department comprehensively analyzed two Stress Cases in this 2006 Proposed Determination. Both Case 1 and Case 2 sufficiently address potential quantitative impacts during the 2006 Revenue Requirement Period.

CASE 1

This Stress Case focuses on decreased Bond Charge and Power Charge revenues resulting from lower sales to its customers, and increased costs of providing energy under existing contracts.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the base case forecast from EEA's long term gas forecasting model.[13]. Lower customer sales by the Department are driven primarily by a decrease in the net short, which can occur as a result of increased URG and/or decreased customer load. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 125% of normal for 2006 and 2007.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2006 and 2007, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2006 and 2007 by 3.3%, 3.6%, 5.1% and 4.4% for June, July, August, and September, respectively. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of 4% in 2006 and

[13] Based on Gas Daily Monthly Index Prices, monthly gas prices have more than doubled year over year 10 times from 1999 though 2003.

2% in 2007. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department's required recovery cost per MWh.

CASE 2

This Stress Case focuses on increased costs of providing energy under existing contracts, and considers increased contract dispatch due to higher customer load and reduced URG.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the base case forecast from EEA's long term gas forecasting model. Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by assuming California and Pacific Northwest hydroelectric production at 75% of normal in 2006 and 2007. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2006 through March 2006 and at one northern California nuclear power plant unit from April 2006 through March 2007. In addition, approximately 650 MW of merchant generation resources in northern California and 1500 MW of merchant generation resources in southern California that are assumed to be available to the market in the Base Case are assumed to be retired for the entire Revenue Requirement Period in this Stress Case. The expected impact of this type of an assumption is to increase the amount of energy dispatched from the Long Term Priority Contracts.

Higher loads are estimated in this case by assuming load growth rates that are 2.0 percentage points higher than those assumed in the Base Case in 2006 and 1.4% higher in 2007. It is assumed that this growth occurs as a result of accelerated economic growth in California and decreases in the expected amount of non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2006 and 2007. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2006 and 2007 by 4.4%, 4.8%, 6.8%, and 5.9% for June, July, August, and September, respectively.

ADDITIONAL OPERATING SCENARIOS CONSIDERED IN DEVELOPING THE 2006 PROPOSED DETERMINATION

Independent from the aforementioned Stress Cases considered in this Proposed Determination, the Department has evaluated the effects of two additional operating scenarios during the 2006 Revenue Requirement Period. The first operating scenario addresses the effects of discontinuing the current practice of pro-rata sharing of revenue from surplus energy sales between the Department and the IOUs. The second operating scenario addresses the manner in which fuel price volatility is calculated within stress cases for the purpose of determining requisite operating reserves. Each of these operating scenarios is discussed in greater detail below.

IOUs RETAIN ALL SURPLUS SALES REVENUES

In previous Revenue Requirement Periods, the income from surplus energy sales was used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers. For the 2006 Revenue Requirement Period, the Department has considered the effects of discontinuing surplus sales revenue sharing between the Department and the IOUs. In this operating scenario, all energy from the Department's long-term energy contracts is deemed delivered to retail end use customers, and each IOU retains all surplus sales revenues. This scenario results in a simplified operational reporting process for DWR's power supply program and the IOUs' administration of DWR's long-term contracts. This scenario may also support the cost follows contracts principles guiding the CPUC's current DWR cost allocation decisions.

The projected effects of this operational change, relative to the Base Case presented herein, include: (1) a reduction in Surplus Sales Revenue of $169 million (a portion of Other Revenue is related to surplus energy sales from 2005); and (2) an increase in total operating reserves of $208 million. The reduction in surplus sales revenue and the need to increase reserves due to increased operational volatility result in a projected increase in Power Charge Revenues of $377 million for the 2006 Revenue Requirement Period.[14] The projected increase in Power Charge Revenues will be collected on increased energy deliveries by the Department to end use customers, leaving the overall Power Charge rate comparable (or slightly lower) to that reflected in the 2006 Proposed Determination. In this scenario, the DWR Bond Charge remains unaffected. While this operating scenario may affect future revenue requirement periods, the Department has assumed that this scenario will not be implemented during the 2006 Revenue Requirement Period.

DETERMINATION OF FUEL PRICE VOLATILITY FOR STRESS CASES

In this Proposed Determination and all previous determinations of the Revenue Requirement, the Stress Case natural gas forecasts were calculated by doubling the Base Case of the natural gas price forecasts. As an alternative to this approach, the Department has considered a Stress Case that employs basic statistical measures using historical monthly prices. The Department uses historical first of the month prices at Henry Hub as source data for this alternative stress case. From this data, the Department then calculates a three standard deviation value of the natural log of percentage change in monthly prices at Henry Hub. The Henry Hub volatility result is then applied to delivery points in California that produces the Stress Case Gas Prices noted in Table D-12 that are less than twice the Base Case and therefore would, if adopted, cause total operating reserves to decrease by $218 million (base case total operating reserves, as projected herein, equal $1.177 billion).

[14] A corresponding decrease in the IOU's revenue requirement of $169 million would reduce the overall effect of this change on the ratepayers within the service territories of each IOU.

TABLE D-12
ALTERNATIVE STRESS CASE – NATURAL GAS PRICE FORECASTS
(Nominal $/MMBtu)

	Henry Hub	**Southern California Border**	**PG&E Citygate**
	2006	**2006**	**2006**
January	$13.01	$12.49	$12.54
February	$12.78	$11.79	$11.86
March	$11.76	$10.95	$11.04
April	$12.44	$12.00	$12.12
May	$15.80	$15.63	$15.78
June	$13.85	$13.52	$13.64
July	$13.88	$13.74	$13.89
August	$13.46	$13.09	$13.20
September	$14.53	$14.20	$14.33
October	$14.02	$13.81	$14.00
November	$14.05	$13.97	$14.24
December	$14.26	$14.26	$14.45
Annual Average	**$13.65**	**$13.29**	**$13.42**

The Department has discussed these additional operating scenarios with its advisors as well as the CPUC and has determined to present these additional operating scenarios for informational purposes and to provide a basis for comment by interested parties during the Department's administrative process associated with this 2006 Proposed Determination. Neither additional operating scenario has influenced the Department's proposed determination of revenue requirements during the 2006 Revenue Requirement Period.

E. KEY UNCERTAINTIES IN THE PROPOSED REVENUE REQUIREMENT DETERMINATION

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2006 Revenue Requirement Period after this Proposed Determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California.

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs:
   a. Potential administrative and legal challenges to DWR's revenue requirements;
   b. Potential litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement; and
   c. Application and enforcement of the Rate Agreement's Bond Charge rate covenant.

2. Collection of Bond Charges and Power Charges:
   a. Potential rejection of Servicing Arrangements or other disruption of servicing arrangements.

3. Certain risks associated with DWR's Power Supply Program:
   a. Long-term power contracts:
      i. Impact of renegotiated contracts;
      ii. Off-system sales volume and price variability; and
      iii. Failure or inability of the suppliers to perform as promised including but not limited to any failure to add new capacity to the grid.

4. Potential increases in overall electric rates:
   a. Changes in general economic conditions;
   b. Energy market-driven increases in wholesale power costs;
   c. Fuel costs;
   d. Hydro conditions and availability;
   e. Market manipulation;
   f. "Block Forward Contracts" consolidated actions; and
   g. Actions affecting retail rates.

5. Potential decrease in DWR customer base:
   a. Direct Access; and
   b. Load departing IOU service.

6. Potential variance in dispatch of DWR contracts:
   a. Actual vs. forecast load variance;
   b. Dispatch coordination between IOUs and DWR; and
   c. Modification of sharing of surplus power sales revenues.

7. Uncertainties relating to electric industry and markets:

   a. Electric transmission constraints; and
   b. Gas transmission constraints.

8. Uncertainties relating to government action:
   a. California Emergency Services Act;
   b. Possible State legislation or action; and
   c. Possible Federal legislation or action.

F. JUST AND REASONABLE DETERMINATION

THE 2003 DETERMINATION

The 2003 Determination was published on August 16, 2002 and provided extensive material leading to the determination by the Department that its revenue requirement for 2003 as determined therein was just and reasonable. Included in that material was background information on the situation California was facing, the Legislative actions taken and the gubernatorial direction leading to the Department's role and participation in power procurement on behalf of retail customers in the IOUs' service territories. Also included was a discussion of the meaning of just and reasonable, and a discussion of the California Administrative Procedure Act. In finding the 2003 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts including the existing market conditions, the portfolio planning process, the procurement activities and the negotiating environment and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 Revenue Requirement proceeding. For further information please refer to Section H. On August 19, 2004, the Department issued a Reconsideration of the Just and Reasonableness of its 2003 Determination. A copy of the Reconsideration is included in the administrative record of this 2006 Revenue Requirement proceeding. The Department has also included its Notice of Reconsideration in the administrative record supporting this 2006 Revenue Requirement proceeding.

THE 2003 SUPPLEMENTAL DETERMINATION

Subsequent to August 16, 2002, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2003 Supplemental Determination, which was published on July 1, 2003. The just and reasonable determination in the 2003 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2004 DETERMINATION

The 2004 Determination was published on September 18, 2003. The 2004 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2004 as determined therein was just and reasonable. In finding the 2004 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts including the existing market conditions, the portfolio planning process, the procurement activities and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2004 SUPPLEMENTAL DETERMINATION

Subsequent to September 18, 2003, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2004 Supplemental Determination, which was published on April 16, 2004. The just and reasonable determination in the 2004 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2005 DETERMINATION

The 2005 Determination was published on November 4, 2004. The 2005 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2005 as determined therein was just and reasonable. In finding the 2005 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts including the existing market conditions, the portfolio planning process, the procurement activities and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 Revenue Requirement proceeding. For further information please refer to Section H.

THE REVISED 2005 DETERMINATION

Subsequent to November 4, 2004, new information became available to the Department. Such new information, resulting from observed market conditions, relating to updated preliminary actual operating results of the Department, and emanating from changes in certain assumptions, led to the Revised 2005 Determination, which was published on March 16, 2005. The just and reasonable determination in the Revised 2005 Determination is, to the extent applicable and not modified herein, incorporated in this 2006 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2006 revenue requirement proceeding. For further information please refer to Section H.

THE DEPARTMENT WILL MAKE A JUST AND REASONABLE DETERMINATION AFTER COMPLETION OF ITS ADMINISTRATIVE PROCESS

Under the terms of the Rate Agreement between the Department and the Commission, and the terms of the Bond Indenture, the Department has agreed to review, determine and revise its Retail Revenue Requirement at least annually.

The Department issues this Proposed Determination of Revenue Requirements for the period January 1, 2006, through December 31, 2006 for public comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this 2006 Proposed Determination is just and reasonable will be made by the Department after review of comments from interested persons. The administrative process may result in the issuance of a determination of revenue requirements for 2006 that differs from this 2006 Proposed Determination.

G. MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, supply and price of natural gas and coal, power transfer capability of major interties, operating costs, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. The Department analyzed the fundamental drivers underlying the electricity market by generating computer simulations of market activity throughout the Western Electricity Coordinating Council ("WECC") region. The PROSYM price forecasting and market simulation tool was used in this analysis.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this 2006 Proposed Determination, the demand and energy forecasts used were those that were described in Section D.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a “single-price” auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only “single-price” market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an “as-bid” environment. In the near-term, the use of a single-price mechanism for the residual net short produces a reasonable assessment of market prices.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = Incremental Production Cost + Start Cost + No-Load Cost + Price Markup

Where:

- Incremental Production Cost is calculated as each station’s fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;

- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;

- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and

- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with

relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.

2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy.

3) Peak Period Bidding: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in the analysis underlying this determination. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

CALIFORNIA AND WECC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)

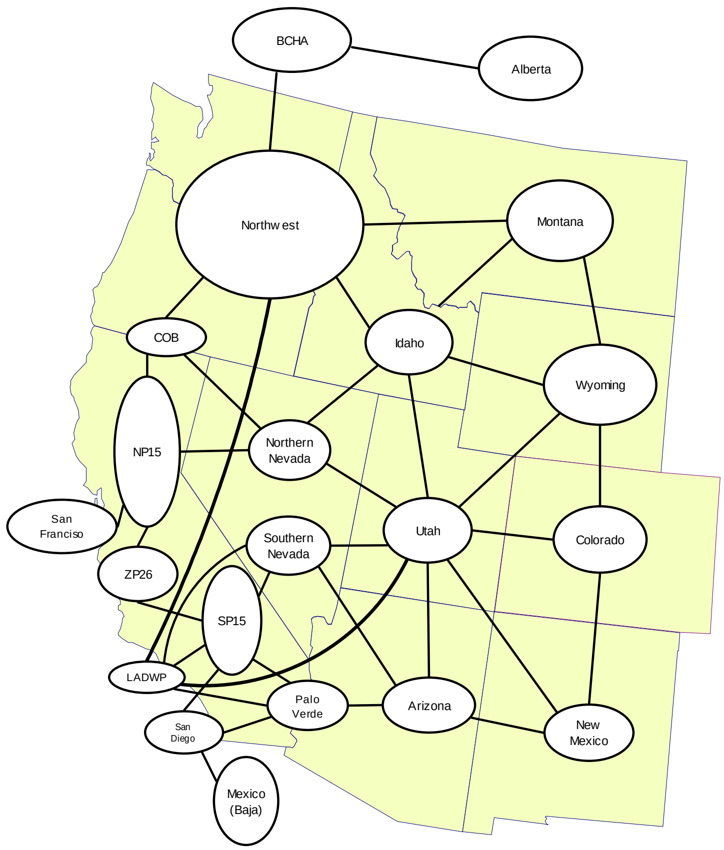
	Incremental	**Price Markup**	**Peak Period Bidding**	**Total**
California	68%	28%	4%	100%
Non-California	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

WECC REGIONAL MARKET DEFINITIONS

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation took into account economic import and export possibilities and set the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.



SIMULATION OF NEW RESOURCE ADDITIONS

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the 2006 Revenue Requirement Period.

GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new generating units are assumed to be added to the resource mix.

LONG-TERM POWER CONTRACTS

The Department's contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the utility retained generation, the Department's contracts, and residual net short purchases. The Department's Long-Term Power Contracts are available for viewing at the Department's web site: http://www.cers.water.ca.gov.

CAISO LOCATIONAL MARGINAL PRICE AND CONGESTION REVENUE RIGHTS PROPOSALS

The California ISO has authorized its staff to develop detailed plans as part of its Market Redesign & Technology Upgrade ("MRTU") to create a structure that establishes locational marginal prices ("LMP") at many different nodes on the CAISO grid. In addition, the CAISO has adopted plans to create Congestion Revenue Rights ("CRR") which could have the effect of requiring the utilities to purchase CRRs to assure the delivery of energy from certain of the Department's long-term energy supply contracts or else risk the possibility of failure to deliver either must-take energy or energy which would otherwise be economically dispatched from the Department's contracts.

Under the MRTU CRR design, the deliverability of capacity and power into and across the California ISO controlled grid may be diminished even for schedules protected by Existing Transmission Contracts ("ETC's"). This is due to two primary elements: 1) the Available Transmission Capacity ("ATC") calculated for use in the CRR allocation process will not be based on the total contract capacity, but rather the "maximum coincident historical transmission capacity reservation on the respective contract path over the most recent 12-month period"; and 2) for ETC's converted to CRR's, the allocation is subject to Simultaneous Feasibility Tests ("SFT") in the allocation process, which may reduce the actual allocation compared to the ETC contract amount.

No such structure existed at the time the Department entered into the long-term contracts, and the Department is unaware of any published analysis by the CAISO or others as to what effect LMP and CRR could have on the delivery of energy from the Department's contracts. To the extent that CRRs need to be purchased to assure delivery of energy under the Department's contracts, such costs would increase the Department's revenue requirement beyond the levels that would otherwise exist. To the extent that others purchase CRRs and such purchases preclude some portion of the Department's energy from being delivered, then the Department assumes that its average cost per MWH of energy will increase and the utilities will need to replace that energy which is not delivered due to this proposed market structure. The extent to which this structure could increase the Department's revenue requirements and the three utilities' separate revenue requirement for the replacement energy they may need to acquire is unknown at this time.

At present, the Department does not expect that the CAISO will implement the LMP and CRR provisions of MRTU until after calendar year 2006 (the Department believes that the timetable associated with MRTU implementation will commence during the fourth quarter of 2007). As a result, the Department does not anticipate MRTU implementation to affect the Department's 2006 Proposed Determination of Revenue Requirements. The Department intends to monitor the CAISO's process for evaluation and implementation of LMP and CRR to better assess and to quantify the possible effects of these structural changes within the energy market.

OTHER ASSUMPTIONS

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2006 through December 2006.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Determination.
Load Profiles	SCE and SDG&E load profiles were provided by the IOUs. The PG&E load shape was based on the composite hourly load profile for the 1993-1998 period contained in PROSYM, The PG&E load profiles were derived from hourly Edison Electric Institute load data files from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	• Multi-segment incremental heat rate curves. • Fixed and variable O&M costs. • Scheduled outages based on annual maintenance cycles. • Random forced outages based on unit-forced outage rates.
Contracts	• Known firm purchase/sales reported in the WECC Form OE-411 filing. • Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity. • Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

H. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE THE PROPOSED DETERMINATION

Volume	Record Number	Date	Record Title
DWR06pRR	001	11/19/2004	CPUC Decision 04-11-014 – Opinion Regarding Municipal Departing Load Rehearing and Related Issues, dated November 19, 2004
DWR06pRR	002	12//7/2004	Energy Action Plan Implementation Meeting Agenda, Energy Report: 2004 and 2005 Overview presentation, and California's Electricity Situation Summer 2005, all dated December 7, 2004
DWR06pRR	003	12/16/2004	PG&E Advice Letter 2548-E-A: Permanent Allocation of the 2004 DWR Revenue Requirement and 2004 Power Charge Remittance Rate Adjustment, dated December 16, 2004
DWR06pRR	004	12/16/2004	CPUC Decision 04-12-046 – Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters, dated December 16, 2004
DWR06pRR	005	12/16/2004	CPUC Decision 04-12-059 – Order modifying Decision 04-11-014 for Purposes of Clarification and Denying Rehearing of the Decision, as Modified, dated December 16, 2004
DWR06pRR	006	12/21/2004	SDG&E Advice Letter 1648-E: Revisions to the DWR Power Charge Remittance Rate Pursuant to D.04-12-014, dated December 21, 2004
DWR06pRR	007	12/23/2004	SCE Advice Letter 1851-E: Revision to the 2004 DWR Power Charge in Accordance with D.04-12-014, dated December 23, 2004
DWR06pRR	008	1/5/2005	DWR letter to the Commission regarding Advice Letters Implementing Decision 04-12-014, dated January 5, 2005
DWR06pRR	009	1/14/2005	Mirant Settlement Agreement: Attorney General Press Release, dated January 14, 2005 (http://caag.state.ca.us/newsalerts/2005/05-005); Mirant 10K pages 37 – 41, dated March 15, 2005 (http://www.mirant.com/financials/pdfs/MIRANTCORP10K.pdf)

Volume	Record Number	Date	Record Title
DWR06pRR	010	1/27/2005	CPUC Decision 05-01-054: "Opinion Resolving The Reasonableness Phase Of Southern California Edison Company's Energy Resource Recovery Account Application". Adopts a joint Southern California Edison Company (SCE) and Office of Ratepayer Advocates (ORA) recommendation to reduce the Energy Resource Recovery Account (ERRA) by a net amount of $3,574,000, reconciling various audit issues. In all other respects, the decision finds SCE's procurement related and other operations were reasonable for the record period September 1, 2001 through June 30, 2003, dated January 27, 2005
DWR06pRR	011	1/28/2005	CPUC Assigned Commissioner's Ruling Placing Consideration of the Sempra, Williams, King River, City and County of San Francisco and Sunrise DWR Contracts in R.04-04-003, Requesting Comments and Alternative proposals for the Allocation of these Contracts and Setting a Prehearing Conference for April 26, 2005, dated January 28, 2005
DWR06pRR	012	2/10/2005	CPUC Decision 05-02-006: "Opinion On The Reasonableness And Prudence Of Southern California Edison Company's Energy Resource Recovery Account". Regarding SCE's ERRA - The power purchase agreements and procurement of least cost dispatch power activities made by SCE for the period beginning July 1, 2003 and ending December 31, 2003 are reasonable and prudent. The procurement-related revenue and expenses recorded in its Energy Resource Recovery Account (ERRA) for that Record Period, resulting in a $141 million ERRA overcollected balance at December 31, 2003 were reasonable and prudent. SCE's $9.7 million Palo Verde Nuclear Unit Incentive Procedure (NUPR) reward amount and its $4.9 million undercollected Electrical Energy Transaction Administration (EETA) Memorandum Account balance at May 21, 2003 were reasonable and recoverable. The decision defers a review of entries recorded in SCE's various generation and delivery service balancing accounts during the Record Period to SCE's April 1, 2005 ERRA reasonableness application, dated February 10, 2005
DWR06pRR	013	2/10/2005	CPUC Decision 05-02-024: Order Denying Rehearing of Decision 05-01-036, dated February 10, 2005

Volume	Record Number	Date	Record Title
DWR06pRR	014	3/16/2005	DWR Revised Revenue Requirement Determination for 2005 including a letter to the Commission regarding Notification of Revised Revenue Requirement Determination for 2005, Notice of Revised Determination of Revenue Requirements, a Summary of Revision to the 2005 Revenue Requirement Determination, and the Revision to the 2005 Revenue Requirement Determination including by reference materials contained within Section J – Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations, dated March 16, 2005
DWR06pRR	015	3/16/2005	DWR Response to Request for Reconsideration of November 4, 2004 Determination of Revenue Requirements, dated March 16, 2005
DWR06pRR	016	3/17/2005	CPUC Decision 05-03-006: "Opinion On Southern California Edison Company's Energy Resource Recovery Account Forecast". This decision adopts a 2005 Energy Resource Recovery Account (ERRA) revenue requirement forecast of $3.16 billion for Southern California Edison Company (SCE). The resulting 2005 system average ERRA generation rate amounts to 5.691 cents/kilowatt-hour (kWh), a 43.78% increase, and the resulting system average ERRA delivery rate amounts to 0.114 cents/kWh, a 70.14% decrease, relative to the 2004 rates, dated March 17, 2005
DWR06pRR	017	3/17/2005	CPUC Decision 05-03-013: "Opinion Modifying Order Instituting Rulemaking". This decision names ESPs and CCAs to the R.04-04-003 (Resource Adequacy Requirements) proceeding, dated March 17, 2005
DWR06pRR	018	3/17/2005	CPUC Decision 05-03-022: "Decision Allocating Southern California Edison Company's Revenue Requirement Of $9.2 Billion". Allocates SCE Revenue Requirement of $9.2 billion including the DWR Power Charge revenue requirement, the DWR Bond Charge, direct access CRS, etc., dated March 17, 2005
DWR06pRR	019	3/17/2005	CPUC Decision 05-03-024: Opinion Allocating the 2005 Revenue Requirement Determination of the DWR, dated march 17, 2005
DWR06pRR	020	3/30/2005	SDG&E Advice Letter 1677-E: Filing in Compliance with Decision 05-03-024, dated March 30, 2005

Volume	Record Number	Date	Record Title
DWR06pRR	021	3/30/2005	Community Choice Aggregation Phase II Workshops and Related Documentation: Section 1. Assigned Commissioner Ruling and Scoping Memo re Community choice Aggregation ("CCA") Proceeding, Phase 2. Section 2. CCA Open Season Workshop 3/3/05. Section 3. CCA Cost Responsibility Surcharge ("CRS")/Vintaging Workshop 3/9/05. Section 4. CCA Tariff Workshops 3/16/05 and 3/29/05 Section 5. CCA Implementation Plan Workshop 3/22/05 Section 6. In-Kind Power Workshop 3/30/05 Section 7. Pre-Hearing Conference 3/30/05
DWR06pRR	022	3/31/2005	DWR Electric Power Fund Financial Statements, dated March 31, 2005
DWR06pRR	023	4/1/2005	PG&E Advice letter 2647-E: 2005 DWR Revenue Requirement Determination, dated April 1, 2005
DWR06pRR	024	4/5/2005	El Paso Corporation Press Release regarding the intent to prepay its Western Energy Settlement obligations, estimated to be approximately $442 million, dated April 5, 2005
DWR06pRR	025	4/7/2005	CPUC Decision 05-04-025: Opinion Allocating the Revised 2005 Revenue Requirement Determination of the DWR, dated April 7, 2005
DWR06pRR	026	4/11/2005	SCE Advice Letter 1886-E: Implementation of April 14, 2005 Consolidated Revenue Requirement and Rate Change in Accordance with Decision Nos. 05-03-006, 05-03-022; and 05-04-025, dated April 11, 2005
DWR06pRR	027	4/13/2005	FERC Order On the Mirant Settlement Agreement, issued April 13, 2005
DWR06pRR	028	4/18/2005	DWR Data Request to PG&E, SCE and SDG&E requesting information for use in the development of the 2006 Revenue Requirement, dated April 18, 2005

Volume	Record Number	Date	Record Title
DWR06pRR	029	4/18/2005	SDG&E Advice Letter 1686-E: Revisions to the DWR Power Charge, DWR Bond Charge and Electric Commodity Rates Pursuant to D.05-04-025, dated April 18, 2005
DWR06pRR	030	4/21/2005	PG&E Advice Letter 2647-E-A: Revised 2005 DWR Revenue Requirement Determination, dated April 21, 2005
DWR06pRR	031	4/21/2005	CPUC Decision 05-04-036: "Opinion Regarding The January 1, 2003 Through May 31, 2004 Record Review Period". Approves PG&E's procurement activities related to its Energy Resource Recovery Account for the period of January 1, 2003 through May 31, 2003, including DWR contract administration and compliance with least cost dispatch, dated April 21, 2005
DWR06pRR	032	4/22/2005	Data Request to IOUs on DA/DL CRS (Rulemaking 02-01-011), dated April 22, 2005
DWR06pRR	033	4/26/2005	Transcript of Preliminary Hearing Conference in Rulemaking 04-04-003, the umbrella rulemaking dealing with all procurement issues and more specifically certain contract reallocations, dated April 26, 2005
DWR06pRR	034	5/6/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: PG&E's responses to the DWR Data Request questions, dated May 9, 2005
DWR06pRR	035	5/9/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: E-mail: El Paso Settlement Distribution, dated May 9, 2005
DWR06pRR	036	5/10/2005	SCE Advice Letter 1886-E: Substitute Sheets for Advice 1886-E. (See 4/11/05 above for initial filing)
DWR06pRR	037	5/10/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: PG&E's responses to the DWR Data Request 002 questions, dated May 10, 2005
DWR06pRR	038	5/11/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: PG&E's supplemental response to the DWR Data Request 001 question 1 (see 5/9/2005 for initial response), dated May 11, 2005
DWR06pRR	039	5/11/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SCE response to the DA DL CRS Data Request 001, dated May 11, 2005

Volume	Record Number	Date	Record Title
DWR06pRR	040	5/13/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Record of Coordination e-mail from SCE, dated 5/13/05
DWR06pRR	041	5/13/2005	PG&E Supplemental Advice Letter 2647-E-B: Revised 2005 DWR Revenue Requirement Determination, dated May 13, 2005
DWR06pRR	042	5/13/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SCE response to the DWR Data Request 001, dated May 13, 2005
DWR06pRR	043	5/17/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Record of Coordination – E-Mails re. Clearwood COD, dated May 17, 2005
DWR06pRR	044	5/17/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Record of Coordination – E-Mails re. Modeling of CPA for 2006, dated May 17, 2005
DWR06pRR	045	5/17/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 001, dated May 17, 2005
DWR06pRR	046	5/24/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: EEA STM Model
DWR06pRR	047	5/24/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: DWR NCI EEA Spring 05 Forecast
DWR06pRR	048	5/24/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: NCI EEA Basecase Assumptions
DWR06pRR	049	5/24/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: WTI Oil Forecast
DWR06pRR	050	5/26/2005	CPUC Resolution Approving the PG&E Implementation of the 2005 Revised Determination of Revenue Requirement
DWR06pRR	051	5/27/2005	PG&E Advice Letter 2647-E-C: Revised 2005 DWR Revenue Requirement Determination, dated May 27, 2005
DWR06pRR	052	5/31/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Record of Coordination – SCE E-mails re. PROSYM Input, May 2005
DWR06pRR	053	5/31/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Meeting with IOUs/CPUC/DWR/NCI, May 31, 2005

Volume	Record Number	Date	Record Title
DWR06pRR	054	5/31/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Power Point Presentation Regarding 2006 Revenue Requirement Status, dated May 31, 2005
DWR06pRR	055	6/6/2005	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Actual Cash Through April 2005 From Filed Model
DWR06pRR	056	6/6/2005	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Analysis Supporting Alternate Scenario – Elimination of Sharing Revenues from Surplus Sales
DWR06pRR	057	6/6/2005	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Analysis supporting alternative Fuel Price Volatility Stress Case
DWR06pRR	058	6/8/2005	DWR Letter to the CPUC Regarding USBA Description